APPENDIX O

CAPACITY CREDITS, INTERMITTENT CAPACITY AND ENERGY VALUE ADJUSTMENTS

O-1. Introduction.

a. Power Benefit Analysis. Chapter 9 presents the basic principles and procedures used in evaluating power benefits. Section 9-3 describes how power values are used in computing power benefits, and Section 9-5 describes how these power values are derived. Principles and Guidelines (77) requires that hydropower benefits reflect power system impacts. This appendix describes techniques that can be used to adjust capacity and energy values to account for these impacts.

b. Source of This Material. This appendix was drawn essentially intact from Chapter 6 of the Water and Energy Task Force report, Evaluating Hydropower Benefits, dated December 1981 (78). Several wording changes have been made to the original text of the Task Force report to reference the 1983 Principles and Guidelines (77) in lieu of the 1979 NED Manual, (79), and to make the material conform to current implementation practices. The text and tabular data relating to mechanical availability (Section O-2d) was revised to reflect current information and practices. Some editorial changes were also made to make the text conform to the standard Engineering Manual format.

O-2. Capacity Value Adjustments and Intermittent Capacity.

a. Introduction.

(1) The capacity benefit computed for a hydropower project is intended to reflect the capacity costs saved by not constructing alternative power generating facilities. Historically, the annual capacity benefits have been computed by multiplying the hydro project's dependable capacity by the annual unit ($/kW) fixed costs of the most likely thermal alternative. This unit cost has normally included an adjustment to reflect differences in operating flexibility and reliability between the hydropower project and its thermal alternative. Aside from the question of what constitutes the most likely alternative to the hydropower project, this historical approach has suffered from three major deficiencies: (a) there are many varying interpretations of the traditional definition of dependable capacity; (b) this definition does not allow proper credit for intermittent capacity which is available a substantial amount of the time but does

not qualıty as dependable capacity; and (c) the reliability/flexibility adjustments applied to the thermal plant unit cost are rather arbitrary and frequently do not reflect current relative performance of thermal and hydropower plants.

(2) Section 2.5.8.(a)(3) of Principles and Guidelines confirms that the concept of a reliability/flexibility credit is valid. Section 2.5.8.(a)(4) recognizes that some credit may be warranted for intermittent capacity. However, Principles and Guidelines fails to provide an effective procedure for resolving the deficienciea cited above.

(3) The basic objective of the capacity benefit is to determine the cost of thermal plant capacity that would contribute the same peak load-carrying capability to a system as the hydropower project. Using a system loss-of-load probability (LOLP) model, the Federal Energy Regulatory Commission's (FERC) Washington office has developed some relationships which make it possible to compute a hydropower plant's capacity benefit directly, considering (a) the hydropower plant's dependable capacity and intermittent capacity, and (b) the relative reliabilities of hydropower and thermal capacity. This approach meets both the capacity value adjustment and intermittent capacity provisions of Principles and Guidelines. Following is a general discussion of the proposed procedure and details for application to specific project studies.

b. The Capacity Benefit Equation.

(1) The basic equation for deriving a hydropower project's capacity benefit is as follows:

$$\text{Capacity benefit} = (IC)(CV) \times \frac{HA}{100} \times \frac{HMA}{TMA} \times (1 + F) \qquad \text{(Eq. 0-1)}$$

where:

Capacity benefit = average annual capacity benefit, dollars
IC = hydropower project installed capacity, kW
CV = thermal plant unit investment cost (capacity value), \$/kW/yr
HA = hydropower project average hydrologic availability (%) during peak demand period
HMA = hydropower plant mechanical availability (%)
TMA = thermal plant mechanical availability (%)
F = hydropower plant flexibility factor

(2) The hydropower project installed capacity is the total rated capacity of the generators, including overload capacity where appropriate. The thermal plant unit capacity value is the average annual unit capacity value of the most likely thermal alternative, without any adjustments for reliability or flexibility. The remaining terms are used to compute the capacity value adjustment and are discussed in more detail in the following sections.

c. Hydrologic Availability.

(1) The dependable capacity of a hydropower project is intended to be a measurement of the amount of capacity that can be counted on as being available when needed. As such, it is intended to reflect hydrologic availability. A project's dependable capacity is frequently less than its installed capacity, because the amount of capacity available when needed may be reduced because of low flows or reduced heads caused by reservoir drawdown or tailwater encroachment.

(2) Various techniques have been used to measure dependable capacity including (a) the amount of capacity available in a selected historical month that is considered most critical from the standpoint of both loads and hydrologic conditions (see Section 6-7d), (b) the amount of capacity available some selected percentage of the time (say 85 percent) in the peakload months (Section 6-7f), and (c) the amount of firm energy required per kilowatt of dependable capacity (Section 6-7e). Values derived using these procedures were very significant when system reliability was measured by reserve margin, and they may still be meaningful in predominantly hydroelectric power systems and for use in negotiating certain types of power sales contracts. However, dependable capacity based on such criteria loses its meaning in large, diverse hydrothermal or predominantly thermal power systems, especially where system reliability criteria are based on the more realistic probabilistic methods, such as LOLP (loss-of-load probability).

(3) It is widely agreed that in most power systems, traditional procedures for measuring dependable capacity frequently underestimate the true value of hydroelectric capacity in a system. This is because most of these procedures are often overly conservative and because no credit is given for intermittent capacity -- capacity that is available a substantial part of the time but does not strictly meet the criteria for dependable capacity. Attempts have been made to recognize intermittent capacity by allowing partial credit, but these attempts are rather arbitrary and difficult to defend technically.

(4) When system reliability is measured probabilistically, the varying availability of hydropower capacity due to variations in head and/or streamflow can be treated in a manner similar to mechanical

availability of thermal plants. In a large diverse power system, the "derating" of a hydropower plant at some particular point in time due to reduced head or low streamflow is a statistical event analogous to the derating or complete shutdown of a thermal unit due to a forced outage. The problem is that a hydropower plant's capacity availability is usually a continuous distribution over a wide range of outputs, unlike a thermal plant which can be represented as on, off, or at several discrete levels of partial output.

(5) In addressing the problem of how to quantitatively measure the hydrologic availability of a hydropower project in a manner in which it could be reflected in a LOLP model, FERC started with a capacity-duration curve, which reflects the degree and amount of time a hydropower project's installed capacity is derated due to reservoir drawdown, tailwater encroachment, or low streamflows. This curve was broken into a number of segments, each representing a discrete "powerplant" of a given size which has an availibility equal to the amount of time that its capacity was hydrologically available during the peak load period. Thus, the hydropower plant was represented in the model as a series of "powerplants" of varying sizes and availabilities. A series of LOLP model runs was made to determine the amount of thermal capacity that would be required to serve the same amount of additional system load as the composite hydropower plant while maintaining the same level of system reliability. By applying this approach to various types of power systems, it was determined that it was not necessary to depict the availability of hydropower capacity as a probability distribution when the hydropower project was relatively small compared to system size. Rather, it could be represented almost as accurately by the hydrologic availability of the hydropower plant's capacity - a single value that could be readily derived.

(6) Various techniques can be used for deriving average hydrologic availability. The values can be derived from capacity or generation-duration curves (Figure O-1) or directly from power routing studies. For simple run-of-river projects, the values should be based on duration curves derived from daily flows and should reflect the impact of minimum unit output and head loss due to encroachment, as well as variations in streamflow. For storage projects or pondage projects on regulated streams, the daily variations in streamflow are not as important. In these cases, the availability can be derived from monthly or weekly routing studies, and it would reflect primarily the variation in machine capability due to variation in head. The analysis should be based only on the system peakload season (e.g., June, July, and August for a summer peak system), because system capacity requirements are normally determined by the annual peak load.

If the hydropower plant cannot deliver any capacity in the peakload months, then it does not displace thermal capacity and hence has no capacity benefit.

(7) For pure run-of-river projects, or projects where operating restrictions preclude regulation of discharge for peaking purposes, the generation-duration curve and capacity-duration curve will be identical. In these cases, the average hydrologic availability factor can be derived from the generation-duration curve, and it will be identical to the plant factor for the peakload months. For projects having hourly load following or peaking capability, the average hydrologic availability factor must be derived from a peaking capacity-duration curve. This curve would be based on daily peak discharges rather than daily average flows, and would it reflect the number of hours per day that the peak discharge must be sustained, the amount of daily/weekly storage available, and any nonpower operating criteria that would limit the plant's ability to peak.

(8) Figure O-2 shows generation and peaking capacity-duration curves for a 16.0 megawatt hydropower project having a hydraulic capacity of 4,000 cfs; a constant head of 56.0 feet; an overall efficiency of 84 percent; a peaking requirement of 6 hours per day, 5 days per week; sufficient weekly storage to accommodate this operation; and a maximum allowable daily discharge fluctuation of 2,000 cfs. Figure O-3 shows the computations supporting derivation of the curve. For this type of operation the average hydrologic availability factor would be about 97 percent. If the project were precluded from peaking operation because of inadequate daily/weekly storage or severe nonpower operating constraints, the average hydrologic availability factor would be about 75 percent.

(9) For most large, diverse power systems, the product of the average hydrologic availability factor and installed capacity could be used in place of the traditional dependable capacity parameter in power benefit computations, and in a sense this product can be considered to be a measure of dependable capacity. For small power systems, isolated power systems, and systems having a high percentage of hydroelectric generation (particularly where all of the hydroelectric generation is influenced by the same hydrologic regime), it may not be appropriate to use the average hydrologic availability concept described above. In these cases, it would be necessary to use dependable capacity values derived using traditional procedures.

d. <u>Mechanical Availability.</u>

(1) The second major factor in the capacity benefit equation is the ratio of mechanical availability, HMA/TMA. This ratio is intended to reflect the relative mechanical reliability of hydroelectric com-

Plant Size (MW)	Area Under Curve 1/	Average Capacity (MW) 2/	Hydrologic Availability (Percent) 3/
8.0	9.74	7.8	97.4
12.0	13.14	10.5	87.5
16.0	14.94	11.9	74.7
20.0	15.80	12.6	63.2

1/ Square inches (on original graph). The graph in this report has been reduced.
2/ 5 square inches equals 4.0 MW.
3/ (Average capacity)/(plant size)

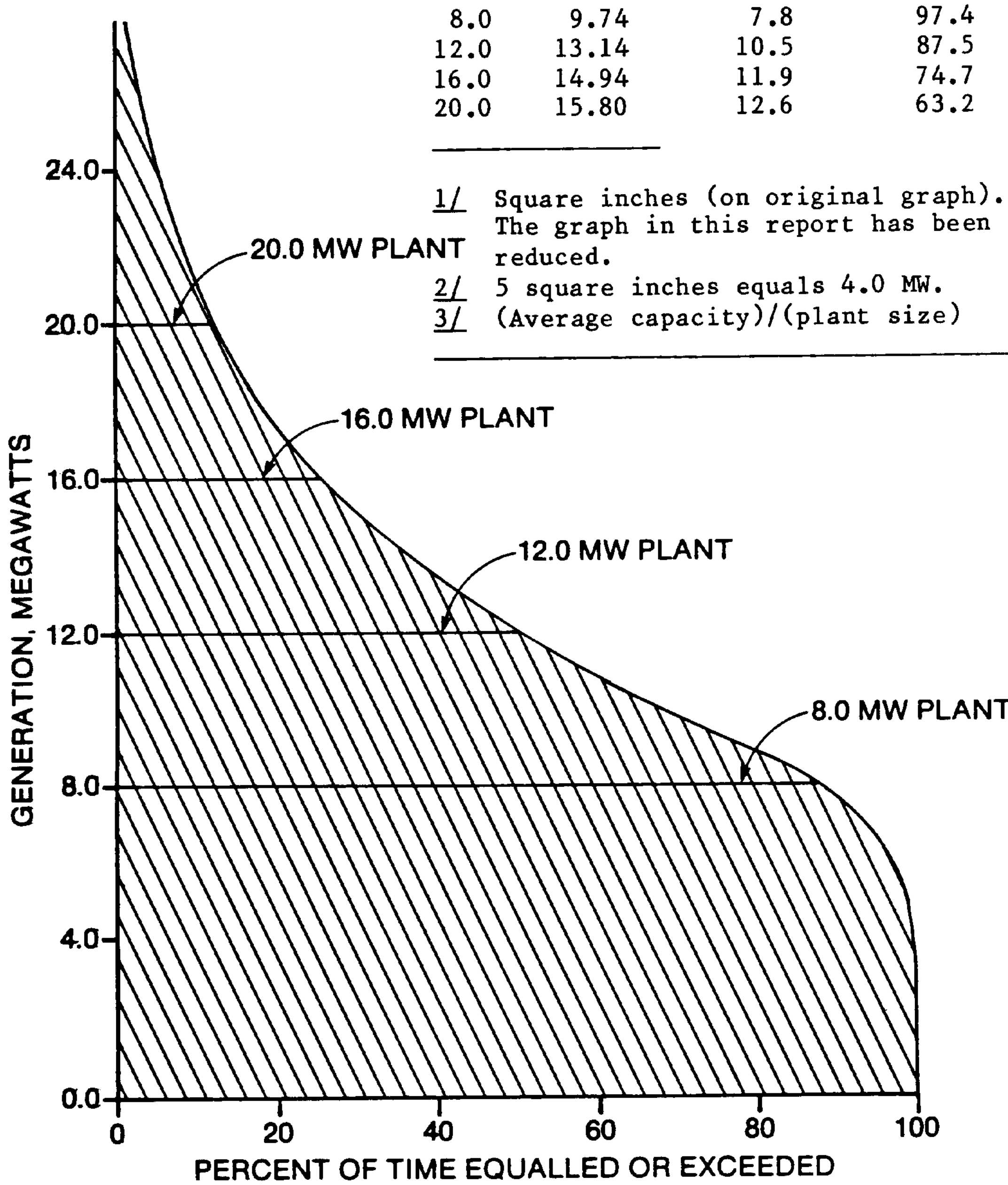


Figure 0-1. Generation-duration curve for hydropower site.

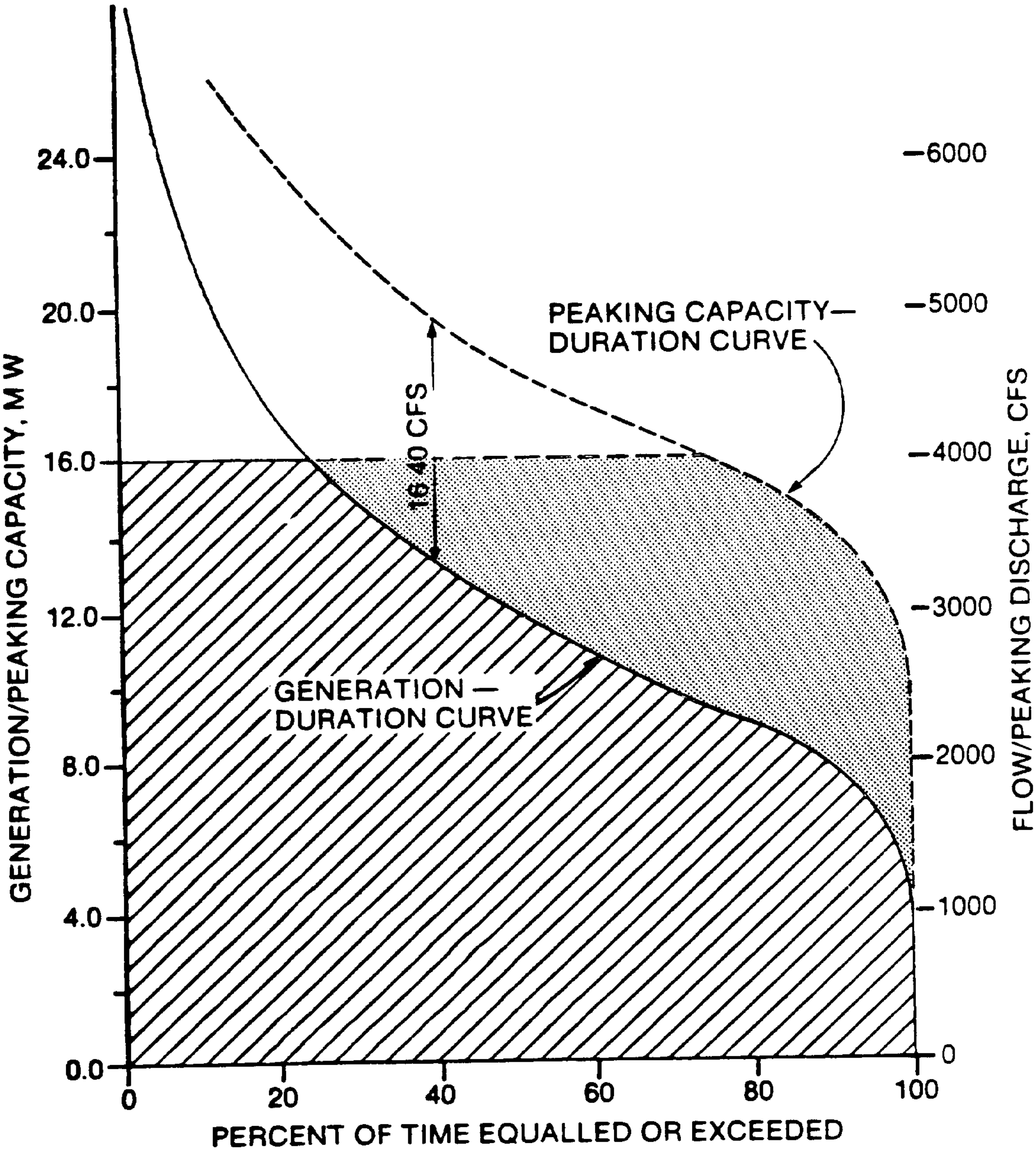
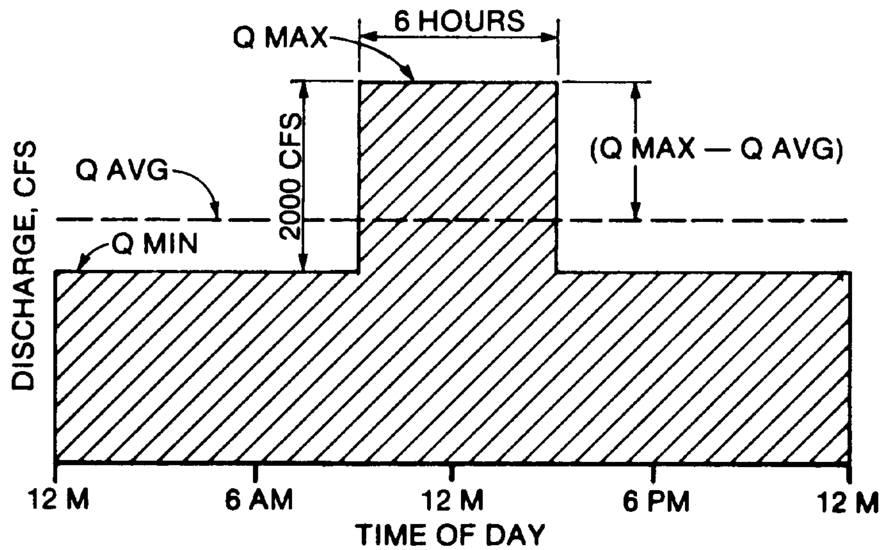


Figure O-2. Generation-duration and peaking capacity-duration curves for a 16.0 megawatt hydropower plant



A typical weekday operation is shown above. It is assumed that this plant would operate five days a week and that the project would discharge at Q_{min} all day Saturday and Sunday.

Q_{avg} = average weekly flow
Q_{max} = peak discharge
Q_{min} = minimum discharge

The allowable (Q_{max} - Q_{min}) is 2,000 cubic feet per second (cfs).

The following two equations describe the weekly peaking operation.

(1) $Q_{max} - Q_{min} = 2{,}000$ cfs

(2) $(Q_{avg})\text{x}(24 \text{ hours})\text{x}(7 \text{ days}) = (Q_{max})\text{x}(6 \text{ hours})\text{x}(5 \text{ days}) + (Q_{min})\text{x}(8 \text{ hours})\text{x}(5 \text{ days}) + (Q_{min})\text{x}(24 \text{ hours})\text{x}(2 \text{ days})$

Solving the two equations simultaneously yields a project dependable peak discharge of (Q_{max} - Q_{avg}), or 1,640 cfs above the average weekly flow. Thus, for each flow level on the flow duration curve, the corresponding point on the peaking discharge-duration curve is 1,640 cfs greater. This is a simplified example for illustration purposes. Detailed hydraulic studies may be required to define Qmax.

Figure 0-3. Derivation of peaking capacity-duration curve pared to thermal generation. (Note: the bulk of the capacity value adjustments formerly used reflected relative mechanical reliability). Normally, mechanical reliability reflects only forced outages, but where maintenance must be scheduled in the peakload months, scheduled maintenance outages should be accounted for also.

(2) Table O-1 is a summary of power plant availabilities, taken from NERC (National Electric Reliability Council) data, which is considered to be representative of recent experience (27). Note that two types of availabilities are presented.

(3) The equivalent availability factor is a standard NERC performance parameter, which reflects the net annual availability once forced outages, scheduled outages, and maintenance outages are deducted. The forced outage availability factor was developed by the Water and Energy Task Force to reflect the reliability of the plants during the peak demand periods. It was assumed that, in most systems, maintenance outages (interim as well as annual maintenance) would not be scheduled during the peak demand hours of the high demand months. Hence, for most types of plants, the forced outage availability factor was defined as 100 percent minus the NERC equivalent forced outage rate (in percent), where the NERC equivalent forced outage rate is defined as the ratio of the forced outage hours to the sum of the service (on-line) hours and the forced outage hours.

(4) However, this definition is not satisfactory for peaking and reserve units, such as combustion turbines, diesel units, and pumped-storage plants. The forced outage rates for these units (which are typically very high) tend to be distorted because of the relatively small number of hours the units operate per year. The forced outage availability values presented for these three types of plants in Table O-1 are instead estimated values, taking into consideration successful start ratios and the average number of forced outages per year, as well as forced outage rates. NERC does not maintain availability data for combined cycle plants, so both values were estimated for this type of plant.

(5) It is recommended that the forced outage availability values be used in most cases as the measure of mechanical availability. However, for systems where maintenance outages cannot be concentrated in the off-peak months (due to extended periods of peak demand and/or a large number of units requiring maintenance), it may be desirable to use values that are between the forced outage availability and equivalent availability factors.

(6) NERC data does not differentiate between conventional hydro units operated for peaking and base load units. However, units that are required to follow load or stop and start frequently typically

TABLE O-1
Summary of power plant availability

	Unit Size (megawatts)	Forced Outage Availability 2/ (percent)	Equivalent Availability 3/ (percent)
Coal fired	100-199	90.0	81.2
Coal fired	200-299	88.1	79.3
Coal fired	300-399	84.2	73.4
Coal fired	400-599	84.9	73.0
Coal fired	600-799	81.5	70.7
Coal fired	800-1200	80.0	69.3
Nuclear	All	82.3	65.2
Comb. turbine	All	85.0 (est.)	86.6 3/
Combined cycle	All	86.0 (est.)	85.0 (est.)
Diesel	All	90.0 (est.)	93.8
Hydro (base load)	All	98.0 4/	95.0 4/
Hydro (peaking)	All	95.0 4/	92.0 4/
Pumped storage	All	93.0 (est.)	85.5

1/ Equivalent availability factor = $\frac{(PH - (FOH + EUDH + POH + MOH))}{PH}$

where: PH = total hours in period (year)
FOH = forced outage hours
EUDH = equivalent unplanned derated hours (partial forced outages)
POH = outage hours (annual maintenance)
MOH = maintenance outage hours (interim maintenance)

2/ Forced outage availability = (100%) - (equivalent forced outage rate, %)
1/ Weighted average of industrial combustion turbines and jet engine type units.
4/ See Paragraph O-2d(6).

have higher outage rates than base load units. Hence, estimated values are presented for both base load and peaking hydro units. It is recommended that base load values be used for pure run-of-river projects and other base load plants, and that the peaking values be used for plants that are expected to see heavy peaking service. Intermediate values could be used for other plants, depending on the degree of peaking operation anticipated.

(7) Where coal-fired units are used as the alternative, availibility should be based upon the size of the coal-fired units that probably would be built in the area (600 MW, for example) rather than on a hypothetical coal-fired plant of the same size as the hydropower plant. Thus, the mechanical availability ratio of a base load hydropower plant compared to a 600-MW coal-fired plant would be;

$$\frac{HMA}{TMA} = \frac{98.0}{81.5} = 1.20 \qquad \text{(Eq. 0-2)}$$

e. Flexibility.

(1) Hydropower traditionally has been acknowledged as having an advantage over most thermal units because of its ability to start quickly, follow load, motor to improve system power factor, and in other ways contribute flexibility to power system operation. Although no attempt has ever been made to precisely quantify the benefits of flexibility, some credit for flexibility has been included in the capacity value adjustments historically used. Now that mechanical availability is treated explicitly, it becomes necessary to make a specific assumption regarding the value of flexibility. It is proposed that a 5 percent flexibility credit be given to hydropower compared to a nuclear or coal-fired unit. Combustion turbine units have many of the same flexibility characteristics as hydropower, and thus a flexibility credit may not be warranted. In some cases, however, a hydro peaking project may have considerable operating flexibility and a small flexibility credit (compared to combustion turbines) may be appnopriate. The basis for such credit should be documented.

(2) Caution should be used in applying this credit. If operating restrictions (such as a limitation on the rate of change in discharge) limit the hydropower plant's inherent ability to respond quickly to demand fluctuations, no flexibility credit is warranted. Similarly, if no daily or seasonal storage is available at site or immediately upstream to permit the plant to shape discharges to follow demand, it is questionable whether this credit should be claimed.

(3) At the time this manual was completed, the Electric Power Research Institute (EPRI) was attempting to develop a methodology for quantifying flexibility, or "dynamic" benefits of energy storage projects of all types, including conventional and pumped-storage

hydro. Reference (68) is the proceedings of a conference sponsored by EPRI to deal with this subject.

f. Implementation.

(1) Traditionally, FERC has handled the mechanics of the capacity value adjustment in computing the capacity value of a hydropower plant. This has been appropriate because of FERC's greater expertise in the areas of powerplant reliability and flexibility. However, with hydrologic availability as a component, it will be necessary for the construction agency to be involved in the capacity value adjustment computation process. The following procedure is proposed:

- FERC will continue to determine the annual investment cost (CV) of the thermal alternative, and will compute that portion of the capacity value adjustment dealing with reliability and flexibility. An adjusted annual investment cost, or adjusted capacity value (adjusted CV), will then be determined.

$$\text{Adjusted CV} = \text{CV} \times \frac{\text{HMA}}{\text{TMA}} \times (1 + F) \qquad \text{(Eq. O-3)}$$

- the construction agency would have the responsibility for deriving the average (or hydrologic) availability factor (HA), based on the peakload period for the area. The average availability factor applied to the installed capacity (IC) would result in an "adjusted capacity" which could be used as a measure of dependable capacity:

$$\text{Dependable capacity} = (\text{IC})(\text{HA}) \qquad \text{(Eq. O-4)}$$

- the construction agency would apply the adjusted capacity value to the dependable capacity to compute project annual capacity benefits:

$$\text{Capacity benefit} = (\text{Adjusted CV})(\text{Dependable cap.}) \qquad \text{(Eq. O-5)}$$

(2) For systems where hydropower is the predominant power source, the use of average hydrologic availability to define dependable capacity will generally not be appropriate. In those cases, dependable capacity as traditionally defined would be used. In such cases, the annual capacity benefits equal the adjusted capacity value times the project dependable capacity.

(3) The term "equivalent thermal capacity" (equiv. thermal cap.) is sometimes used to describe the amount of thermal capacity which

would be displaced by the hydro plant. This would be computed as follows:

$$\text{Equiv. thermal cap.} = (IC)(HA) \times \frac{HMA}{TMA} \times (1 + F) \qquad \text{(Eq. 0-6)}$$

Equivalent thermal capacity would be used in computing capacity benefits only if the capacity values provided by FERC did not include the adjustment for mechanical availability and flexibility.

(4) The following example illustrates how capacity benefits would be computed using the procedure described above.

Given: Hydropower project installed capacity (IC)= 16.0 MW
Hydropower project mechanical availability (HMA) = 98.0 percent
Thermal alternative = 600 MW baseload coal-fired plant
Thermal plant mechanical availability (TMA) = 79.0 percent
Unadjusted capacity value (CV) = \$100/kW-yr
Assume hydropower plant has daily/weekly storage and no operating restrictions which would limit flexibility. Therefore, flexibility credit (F) = 0.05

$$\text{Adjusted capacity value} = (\$100/\text{kW-yr}) \frac{(98.0)}{(79.0)} (1 + 0.05) = \$130/\text{kW-yr}$$

From the peaking capacity duration curve for the peakload months (Fig. 0-2), the average hydrologic availability of the 16.0 MW hydropower plant is estimated to be 97 percent.

Dependable capacity = (0.97) x (16.0 MW) = 15.5 MW
Capacity benefit = (\$130/kW-yr) x (15.5 MW) = \$2,020,000

(5) If the hydropower plant were a pure run-of-river plant with no daily/weekly storage and/or operating restrictions which limit operating flexibility, the flexibility credit would be zero.

$$\text{Adjusted capacity value} = (\$100/\text{kW-yr}) \frac{(98.0)}{(79.0)} (1.0) = \$124/\text{kW-yr}$$

The average hydrologic availability factor would be based on the generation-duration curve (Figure 0-1), rather than the peaking capacity-duration curve, and would be 75 percent.

Dependable capacity = (0.75)(16.0 MW) = 12.0 MW
Capacity benefit = ($124/kW-yr)(12.0 MW) = $1,490,000

O-3. Energy Value Adjustment.

a. Conceptual Basis of Energy Value Adjustment.

(1) Section 2.5.8(a)(2) of *Principles and Guidelines* requires that "the effect on system production expenses shall be taken into account when computing the value of hydroelectric power." If a hydroelectric plant is selected instead of a thermal powerplant to meet the requirements of load growth, the hydropower plant may result in the costs of operating the other powerplants in the system being either greater or lesser than if the thermal alternative were added to the system. For example, the installation of a new baseload thermal plant instead of a peaking hydropower plant would reduce the hours of operation of existing, more costly thermal generating facilities, and thus effect a decrease in system production costs. Conversely, the addition of thermal-peaking capacity, such as combustion turbines, rather than peaking or low-plant factor hydroelectric capacity could result in an increase in system production costs.

(2) In such cases, it is appropriate to introduce an adjustment in the economic analysis of the energy components of the hydroelectric plant. When the alternative thermal generation would lower the system's average cost of thermal energy, this adjustment should be negative. The adjustment should be positive if the alternative thermal generation would increase the system's average cost. Where the adjustment changes with time, present worth procedures should be used in determining the average energy value adjustment over the life of a project. For convenience of computations, the net adjustment should be applied to the market cost of the alternative thermal-electric energy. The adjusted cost is the market value of hydro-electric energy.

b. Methods for Calculating Adjustment. The effect of system production expenses can be accounted for in two ways. Energy value reflecting system costs can be computed directly through the use of system production cost models. If such a model is not available, an adjustment factor can be estimated through use of an equation. This "energy value adjustment" can be applied to the cost of energy produced by the alternative thermal plant to obtain an adjusted energy value which reflects the impact of system costs.

c. System Models. The use of system models such as POWRSYM (see Section 6-9f) would involve making detailed comparative analyses of annual system production expenses with, alternatively, the hydroelectric project and equivalent amounts of each type of alternative thermal capacity deemed appropriate. Applicable variable costs of fuel and operation and maintenance would be assigned to all generating plants in the system, and the total annual system production expenses would be determined for each type of capacity being considered. The difference between the total system costs with the hydroelectric project and the total system costs with the most likely thermal-electric alternative, divided by the avevage annual energy output of the hydroelectric project, gives an adjusted energy value for the particular year being considered. Successive evaluation of ensuing years, and the use of present worth procedures, can be used to determine the equivalent levelized energy value applicable over the economic life of the hydroelectric project.

d. Equations. Instead of these detailed studies, the unit energy value (or capacity value) adjustments may be approximated in any year by the following equations:

$$E_n = \frac{PF_t - PF_h}{PF_h} \times \Delta C \qquad \text{(Eq. 0-7)}$$

or:

$$CP_n = (PF_t - PF_h)(\Delta C) \times \frac{\text{(8760 hours/year)}}{\text{(1000 mills/dollar)}} \qquad \text{(Eq. 0-8)}$$

where:
- E_n = Energy value adjustment for the year, in mills per kilowatt-hour of hydroelectric generation
- CP_n = Capacity value adjustment for the year, in dollars per kilowatt-year of dependable hydroelectric capacity
- PF_t = Plant factor of the alternative thermal-electric plant
- PF_t = Plant factor of the hydroelectric plant
- ΔC = $EC_t - EC_d$
- EC_t = Energy costs (mills per kilowatt-hour) of the thermal alternative
- EC_d = Average energy cost of those plants which the thermal-electric alternative might reasonably be expected to displace.

By making assumptions as to the plant factor of the alternative thermal plant, and the difference in energy costs between the alternative plant and those plants it might replace, Equations 0-7 and 0-8 may be used to derive periodic estimates of energy value and capacity value adjustments. By the use of present worth procedures, an average equivalent adjustment applicable over the assumed life of the hydroelectric project may be computed.

e. Impact of Adjustment. It should be noted that the energy value adjustment can be a significant factor in the overall power value of a hydroelectric project where there is a considerable difference in the plant factors of the thermal-electric alternatives and the proposed hydroelectric project, or where there is a wide range between the thermal-electric alternative energy costs and the average energy costs of the plants it would replace. Due to the potential impact of such adjustments on final hydroelectric power values, every hydroelectric power evaluation must consider these adjustments.

f. Selection of Method. The use of a system model is the preferred method because it is very difficult to estimate EC_d without using a model. FERC has several models which can be used for this purpose, and they are in the process of implementing these models for their power value work on a region-by-region basis as manpower permits. In regions where models are not yet operable, the approximate equation method is being used on an interim basis. The approximate, or "short-cut" equation method will probably continue to be the most practical method for evaluating small isolated systems, as in Alaska. The hydro-dominated Pacific Northwest power system cannot be evaluated using a standard production cost model such as POWRSYM, but the regionally developed system analysis model (SAM) has been adapted for analysis of energy benefits for this system. The Bureau of Reclamation is investigating the use of generating expansion models, which also account for system energy cost impacts for use in deriving power benefits.